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EFFECTS OF PRODUCED SAND ON SHORT DISTANCE PIPELINE TRANSPORTATION OF HEAVY OIL IN WATER EMULSIONS: SRC PIPELOOP TEST RESULTS

Final Report by

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SUMMARY

The flow behaviour of high concentration heavy crude oil in water emulsions was studied by using a 53 mm diameter recirculating flow pipeline loop at the Saskatchewan Research Council. The project was funded and supervised by Amoco Canada Petroleum Company Ltd., PanCanadian Petroleum Limited and Westmin Resources Limited. Partial funding was provided by Energy Mines and Resources Canada.

The test results confirmed the potential of oil/water emulsion technology for reducing heavy oil pipeline operating costs. Under the laminar flow conditions of the tests, the pumping energy required to transport an emulsion containing 70% crude oil was only about 1% of that required to transport the heavy crude oil alone.

The effects of temperature and sand content on the flow resistance of high concentration oil in water emulsions were studied experimentally. The effect of temperature could be explained through changes in the viscosity of the brine used to prepare the emulsions. Sand in the oil either increased or decreased the flow resistance depending upon the amount of water present initially in the oil. Sand concentrations in the flow experiments were limited to 3% (mass) of the produced oil. The sand flowed in a distinct layer at the bottom of the pipe and the velocity necessary to transport the sand was strongly dependent on emulsion effective viscosity.

The tests showed that emulsion durability increased with surfactant dosage and water content and decreased rapidly with increasing sand content. Emulsion durability was also affected by the type of pump used to

recirculate the mixtures. Emulsions were short–lived when a centrifugal pump was used but survived longer with a progressing cavity (screw) pump and still longer when an oilfield gear pump was installed in the test pipeline.

Velocity distribution measurements and a finite element simulation showed that a region of low viscosity forms at the pipe wall as a result of oil droplet migration into the flow. The droplet migration phenomenon is not well understood and the magnitude of the effect is likely to be pipe size dependent. Because the flow is complex, it is not advisable to use single phase fluid viscometric models to estimate frictional headlosses and laminar/turbulent transition conditions for larger pipe diameters. Further work, particularly in large diameter pipes, is required before field pipelines can be designed with confidence. Further work is also required to assess the effects of sand on emulsion durability and the potential for corrosion/erosion in pipelines carrying oil/brine/sand mixtures.

RÉSUMÉ

Les caractéristiques d'écoulement d'émulsions à haute concentration de pétrole brut lourd dans l'eau ont été étudiées au Saskatchewan Research Council à l'aide d'un pipeline en circuit fermé de 53 mm de diamètre. L'étude a été subventionnée et supervisée par Amoco Canada Petroleum Company Ltd., PanCanadian Petroleum Limited et Westmin Resources Limited. Une partie des subventions a également été fournie par Énergie, Mines et Ressources Canada.

Les résultats des essais entrepris ont confirmé que la technologie des émulsions pétrole–eau peut contribuer à la réduction des coûts d'opération des oléoducs à pétrole lourd. Dans les conditions de flux laminaire des essais effectués, l'énergie de pompage nécessaire pour le transport d'une émulsion contenant 70% de pétrole brut est d'environ 1% de celle nécessaire pour le transport du pétrole brut seul.

On a également effectué des expériences pour déterminer les effets de la résistance à l'écoulement des émulsions à haute concentration de pétrole brut lourd dans l'eau. Les effets de la température peuvent être interprétés comme résultant des différences de viscosité de l'eau salée utilisée pour préparer les émulsions. La présence de sable dans le pétrole soit augmente soit diminue la résistance à l'écoulement, selon la quantité d'eau présente au départ dans le pétrole. Les concentrations en sable dans les expériences d'écoulement furent limitées à 3% (en masse) du pétrole produit. Le sable s'écoule sous la forme d'une couche distincte située au fond de la conduite

et la vitesse nécessaire pour transporter le sable dépend fortement de la viscosité effective de l'émulsion.

Les essais ont montré que la stabilité de l'émulsion dans le temps augmente avec la quantité de tensioactif et la quantité d'eau, et diminue rapidement lorsque contenu en sable augmente. La stabilité de l'émulsion dépend aussi du type de pompe utilisé pour recycler les mélanges. Les émulsions se sont dégradées rapidement avec une pompe centrifuge, mais sont restées stables plus longtemps avec une pompe à vis et davantage encore lorsqu'une pompe à engrenage telle que celles utilisées dans les champs pétrolifères fut employée dans le circuit.

Des mesures de la distribution des vitesses et une simulation en éléments discrets ont montré qu'une région de faible viscosité se forme à la paroi de la conduite, suite à la migration des gouttelettes de pétrole vers l'intérieur du flot. Ce phénomène de migration de gouttelettes n'est pas bien expliqué et son effet est probablement fonction de la taille de la conduite. Etant donné que l'écoulement est complexe, il est déconseillé d'utiliser des modèles viscométriques à phase unique pour l'estimation des pertes de front dues à la friction ou des conditions de transition d'un écoulement laminaire vers un écoulement turbulent dans des conduites à diamètre plus important.

Des travaux supplémentaires seront nécessaires, en particulier dans des conduites à grand diamètre, avant que l'on puisse envisager avec assurance la conception d'oléoducs à être employés sur le terrain. Des travaux supplémentaires seront également nécessaires pour l'évaluation des effets du sable sur la stabilité des émulsions et de la possibilité de corrosion et/ou d'érosion des conduites transportant des mélanges pétrole–eau salée–sable.

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1. INTRODUCTION

Crude petroleum is a multiphase mixture of oil, water, sand and gas whose flow properties are known to be complex. For these mixtures, the resistance to flow depends strongly on the nature of the continuous phase. With no gas phase present, the flow resistance can be minimized by using a surfactant to ensure that an oil in water emulsion forms.

Heavy oil producers in the Lindbergh, Alberta area are examining emulsion technology to improve the performance of oilfield pipeline gathering systems. Widespread use of flow lines would reduce truck traffic and minimize the proliferation of surface facilities.

Emulsions for short distance flow lines must be easy to prepare using produced water, a minimal amount of chemical additive and simple mixing equipment. These emulsions need not be very durable but the oil and water must separate readily once the emulsion enters the treating facility.

Unlike long distance emulsion pipelines, these short distance gathering systems may have to cope with substantial amounts of produced sand and highly variable flow rates.

This investigation considered the effects of temperature and sand content on the flow resistance of high concentration heavy oil emulsions. The emulsions were prepared with moderate shear using fairly low surfactant concentrations in an attempt to simulate flow in gathering system pipelines.

Sand transport by fluids in turbulent flow is comparatively well understood, but little is known about laminar flows. Since high concentration oil in water emulsions have high viscosities, laminar flow is likely to occur and the test program considered this type of flow.

2. EMULSION FLOWS

The resistance to flow of a single phase or multiphase mixture in a pipeline is expressed in terms of the frictional pressure gradient (kPa/m). For single phase fluids this is a linear function of the viscosity as long as the flow is laminar.

$$\Delta P/L = 32\ \mu V/D^2 \qquad (1)$$

and the viscosity can be measured conveniently in a variety of viscometers which do not involve pipe or tube flow.

Equation (1) is frequently employed for emulsions but the viscosities which are inferred from equation (1) can differ from the values obtained with viscometers. The difference has been attributed to droplet migration away from the pipe wall (Wyslouzil et al, 1987) to leave a region of low concentration.

Experiments conducted with viscometers have shown that the relative viscosity, the ratio of the mixture viscosity to that of the carrier fluid:

$$\mu_r = \mu_m / \mu_L \qquad (2)$$

depends strongly upon the concentration of the dispersed phase. It is also a function of the size and size distribution of the particles or droplets. If agglomerates form the flow is non–Newtonian and the "viscosity" depends upon shear rate in the viscometer. In pipe flow agglomerates would cause μ in equation (1) to vary with V.

As the concentration of oil in water emulsions rises a point is eventually reached at which insufficient water is available to form the continuous phase. The emulsion then inverts to a water in oil dispersion whose mixture viscosity

is proportional to that of the oil, according to equation (2). The flow resistance rises correspondingly.

Previous work with heavy oil in water emulsions showed that the effective viscosity varied with recirculation time for experiments conducted with closed loop circuits (Shook, 1985, Wyslouzil, 1987). An initial decrease in effective viscosity was attributed to production of a broader droplet size distribution, possibly as a result of coalescence of some of the droplets. It seemed likely that some water was incorporated in the droplets during coalescence, increasing the concentration of the dispersed phase. This was inferred from the fact that the effective viscosity passed through a minimum, followed by inversion in several cases.

To stabilize emulsions, a surfactant is used to increase the repulsive force between oil droplets. The necessary quantity of surfactant will be proportional to the surface area of the dispersion and for this reason very small droplets are undesirable in field operations. High shear mixers are frequently used in laboratory studies to produce very small droplets which segregate or cream very slowly under gravity. However, for short distance field application, a lower shear method of preparation appeared to be more practical.

3. EXPERIMENTAL PROGRAM

The experimental test pipeline is shown schematically in Figure 1. It consists of a loop of steel pipe, 53 mm I.D. and approximately 30 m in length. By circulating heating or cooling fluid through the double pipe heat exchanger, the temperature could be controlled during the experiments. The variation of temperature along the pipeline was of the order of 1–2°C.

Two different crude oils were used in the tests. They were obtained from different leases in the Lindbergh field and differed primarily in their water contents. The Amoco oil contained 3% water and the Westmin oil contained 14% water. The raw crude oil, brine and sand samples were removed from lease tanks and did not contain any oilfield chemicals. The physical properties of the raw oils and of the field brines used to prepare the emulsions are given in Table 1.

Emulsions were prepared by mixing the surfactant with the brine in the reservoir above the pipe. Crude oil was then added slowly while the mixture was stirred at 600 – 1200 r.p.m with a 15 cm diameter "high–shear" impeller. After the addition was complete, the emulsion was mixed for one minute at 2350 r.p.m.. Crude oil and brine from the Amoco lease were used to prepare Oil A emulsions while oil and brine samples from the Westmin lease were used to form Oil B emulsions. A common sand sample (from Westmin's lease) was used for all tests. The sand particle size distribution is shown in Table 2.

Although droplet sizes were not measured in this investigation, samples of the mixture removed for viscosity measurements showed that the droplet size was directly related to the surfactant concentration. A commercial

Table 1: Crude Oil and Brine Properties for Emulsion Pipelining Study

Densities and Viscosities

		11°C	20°C	40°C
Oil B	Density (g/cc)	0.992	0.987	0.975
Oil A	Density (g/cc)	0.996	0.991	0.978
Brine B	Density (g/cc)	1.059	1.056	1.048
Brine A	Density (g/cc)	1.045	1.042	1.036
Brine B	Viscosity (cp)	1.47	1.20	0.83
Brine A	Viscosity (cp)	1.42	1.17	0.81

Raw Crude Oil Compositions by Mass

	Dry Oil	Water	Sand
Oil A	97%	3%	<0.1%
Oil B	86%	14%	<0.1%

Sample sources:

Oil A, Brine A – Amoco Canada Petroleum Company, Lindbergh Field

Oil B, Brine B – Westmin Resources, Lindbergh Field

Table 2: Particle Size Distribution of Produced Sand Sample

Sieve Opening (mm)	0.297	0.210	0.149	0.105	0.074	0.044
Fraction Retained	0.002	0.004	0.039	0.162	0.677	0.856

oil field surfactant was used in the present investigation. The surfactant, called "Ho–Flow" was supplied by Petroferm Inc.

Preliminary work conducted at a concentration of 500 p.p.m. (surfactant/ crude oil) showed that the time to inversion depends strongly on the added water content and on the type of pump used to circulate the mixture. These results are shown in Table 3. The centrifugal pump was most unsatisfactory and the gear pump was considerably better than the progressing cavity (screw) pump.

A series of bench scale experiments was then conducted to determine the durability (time to inversion) as a function of surfactant concentration. Emulsions were prepared in 500 ml beakers with stirring at 550 ± 50 r.p.m. Flow was simulated by subsequent stirring at 2500 r.p.m. Durabilities are shown as functions of surfactant concentration (both crudes) and added brine fraction (oil B) in Figures 2 and 3. These results substantiate the qualitative conclusions drawn from the preliminary pipeline work. As the surfactant concentration increased the emulsions had a more uniform texture and their durability increased.

Table 3: Effect of Pump Type on Emulsion Durability

Pump	Oil	Dry Oil (%)	Free Water (%)	Time to Inversion (hr)
Progressing Cavity	B	<60	>30	4.0
Progressing Cavity	B	60	30	1.6
Centrifugal	B	60	30	0.2
Gear	B	60	30	4.3
Gear	B	70	18	0.0
Gear	A	70	28	1.1

The main series of pipeline flow tests was conducted at a concentration of 2000 p.p.m.. While this chemical dosage was required for proper testing in the recirculating pipeloop, a much lower dosage may be optimal for field applications. It has been reported that chemical dosages an order of magnitude lower than this are adequate in field tests where the emulsion does not pass through a pump.

The first experiments investigated the effects of temperature and recirculation time for emulsions of high oil concentration. Figure 4 shows the flow resistance for emulsions prepared from oil A in the form of headloss plotted against the mean flow velocity. Velocities were determined from the pump speed and were verified with the magnetic flux flowmeter in the test loop. At 40°C, the headloss was a linear function of velocity, suggesting that equation (2) is appropriate for the emulsions and that the pipeline flow is entirely laminar. At the two lower temperatures, considerable curvature in the headloss versus velocity relationship occurs and the flow resistance decreases with increasing velocity. This is not a time effect since very similar results were obtained when the tests were repeated one hour later.

The results obtained with oil B were very similar, as shown in Figure 5. Only at the lowest temperature was a definite curvature (non–Newtonian flow resistance) evident and there was no significant change in flow resistance with time.

Although Figures 4 and 5 show that a significant variation in effective viscosity can be produced by flow, it was desirable to try to relate the measurements to each other approximately. An apparent viscosity was

determined from the low velocity slopes of the headloss versus velocity relationship using equation 1. These were then expressed as relative viscosities (equation 2) using brine viscosities measured with a capillary tube viscometer. These are shown plotted against the volume fraction of excess brine in Figure 6. It is known that for mono–size solid spheres the relative viscosity versus dispersed phase concentration relationship can be fitted by a relationship of the type: (Mooney, 1951)

$$\mu_r = \exp\{BC/(1-C/C_{max})\} \qquad (3)$$

where B=2.5 and C_{max}=0.63. For the emulsions the values required to correlate the data were B=1.75 and C_{max}=1.0. The difference in these coefficients reflects the breadth of the size distribution of the droplets, any droplet deformation during flow and any inward migration of droplets from the pipe wall. The correlation in Figure 6 is reasonably satisfactory, suggesting that the complicating effects were similar in emulsions of the two oils. It also suggests that most of the water in the oil remained there when the emul–sions were prepared.

Figure 6 does not provide an explanation of the curvature of the headloss versus velocity relationships however. When the emulsions were tested in a single–spindle Brookfield viscometer, the effective viscosity varied with the rate of spindle rotation even when tests were conducted under conditions which corresponded to the low velocity region of Figures 4 and 5. Mean viscosities, suitably normalized, are also shown in Figure 6. They show that a viscometer can be used to estimate the flow resistance of an emulsion dispersed with 2000 p.p.m. surfactant. Further discussion of Figure 6 will be given later.

The effect of sand in the crude oil was then investigated experimentally. Sand from the Lindbergh field was added to the crude oil and the emulsions were prepared as before.

In contrast with the apparent behaviour of the water in the crude, the sand was seen to separate into the aqueous phase and form a layer at the bottom of the pipe during flow. Even low sand contents affected flow resistance significantly. Sand contents are expressed as percentages of the crude oil used in preparing the emulsions. A sand in crude oil concentration of 3% by mass is approximately equivalent to an oilfield BS+W bulk volume concentration of 2%. The results for oil A are given in Figures 7 and 8. The results are qualitatively similar to those in Figure 4 but the flow resistances are higher. There was no time effect in this case.

Corresponding results for oil B are given in Figures 9, 10 and 11. Here there is a significant difference in that the flow resistances fall with increased sand content and with time. The major difference between the two oils is that oil B contained about 14% water dispersed as fine droplets in the oil while oil A contained only about 3% dispersed water. The pipeloop test results suggest that the sand carried some of the water originally in oil B into the aqueous phase of the emulsion thus increasing the continuous phase concentration.

In summary, it appears that the addition of the sand had two opposing effects on the frictional headloss of the mixture:

1. Sand addition tended to increase the frictional headloss of the mixture by adding to the dispersed phase volume fraction.

2. Sand addition tended to carry water from the dispersed phase to the continuous phase and, thus, tended to reduce the frictional headloss for emulsions formed from crudes with high water contents.

The flow resistances shown in Figures 7 to 11 cannot be expressed as apparent viscosities because the flow was essentially heterogeneous. Satisfactory scaleup of such flow test results requires a mechanistic model.

A characteristic of heterogeneous flows of sand suspensions is the accumulation of sand particles along the bottom of a horizontal pipe below a limiting deposition velocity. Deposition velocities have been studied extensively for turbulent flows but very little is known about the phenomenon when the flow is laminar. All the flows in these tests were laminar and Table 4 summarizes the results. The deposit velocities are all comparatively high. They decrease significantly as the viscosity of the emulsion increases and the effect is much stronger than would be observed in turbulent flow. If a deposit of sand forms, the headloss in a field pipeline can be much higher than the values shown in Figures 7 to 11.

The durability of the emulsions was strongly dependent on sand content. Figure 12 shows this effect as determined in benchscale tests. Addition of 10% sand to an oil B emulsion caused it to invert almost immediately in a bench scale test. 3% sand reduced the life of an emulsion by 50%. Although further work would be required to determine the mechanism of the change, it is possible that the sand immobilizes sufficient water to prevent it from forming the continuous phase.

Table 4: Sand Deposition Velocities (m/s) for Heavy Crude Oil/Water Emulsions

Oil	Sand Content (mass %)	11°C	20°C	40°C
B	0.5	0.4	0.6	0.8
B	1.5	0.6	0.8	1.0
B	3.0	0.6	0.8	1.0
A	0.5	0.2	0.4	0.4
A	3.0	0.2	0.4	0.6

4. INTERPRETATION EXPERIMENTS

In order to understand the causes of the velocity dependent flow resistance observed with the oil and brine alone, an attempt was made to measure the velocity distribution within the pipeline. If the emulsions were truly homogeneous then this distribution would be parabolic, with maximum velocity 2V, where V is the mean or bulk velocity.

Because Pitot tubes are known (Barker, 1922) to give erroneous results in laminar flows, an extensive set of calibration measurements was conducted using high viscosity oils in laminar flow in the pipeline. The instrument correction factor appeared to be a function of the velocity gradient (and therefore of the pipe diameter). Thus when the Pitot tube was used in emulsion flows, only the normal (uncorrected) Pitot tube velocity versus tube pressure difference relationship was employed.

The point velocity measurements showed a much flatter profile than would be produced by a homogeneous emulsion. Bearing in mind the suggestions of inward droplet migration (Wyslouzil, 1987), it was decided to try to determine the magnitude of this effect, in order to assist any subsequent mechanistic modelling of these flows.

The pipe cross-section was considered to be divided into 150 triangular finite elements, as shown in Figure 13. The viscosity of the emulsion was assumed to vary primarily with distance from the pipe wall and secondarily with elevation, as shown in Figure 14 for the vertical plane. The primary viscosity change was assumed for all the elements at the pipe wall. The changes assumed in Figure 14 imply substantial wall migration and a small amount of creaming during flow.

A finite element computer solution of the appropriate equations for laminar pipe flow (Fenner, 1975) was then performed. With the viscosity variation assumed in Figure 14, the mean flow velocity from the computer solution agreed with the measured value. The simulation was conducted for an oil B emulsion flowing at a velocity of 1.87 m/s. The apparent viscosity of the mixture was 0.08 Pa–s, a value strongly influenced by the region near the pipe wall.

The test of the assumed viscosity variation is of course its ability to explain the flatter velocity distribution for a given value of V. Figure 15 compares the values predicted by the computer simulation to the Pitot tube (uncorrected) measurements. The small difference between the measurements and the predictions can be attributed to the correction which should be applied to the Pitot tube measurements.

Figure 15 appears to confirm the droplet migration hypothesis. The most likely cause of the velocity dependence of flow resistance, seen in Figures 7 to 11, is that the migration tendency increases with velocity. Although other viscosity versus position functions could give an equally satisfactory agreement in Figure 15, it is likely that all of these would have the features shown in Figure 14.

The point velocity measurements and the simulation suggest that these emulsion flows are more complex than the apparent correlation in Figure 6 would imply. For example, the transitions from laminar to turbulent flow may not be predicted reliably using apparent viscosities or effective viscosities obtained in viscometer tests. Alternatively, the ability of an emulsion to transport sand may be considerably different from that of a homogeneous oil

of the same apparent or effective viscosity. It has not been possible to devise a suitable sand transport model from the results of the experiments shown here. To do so would require further investigation of the durability decrease shown in Figure 12, as well as an investigation of the flow in the sand–rich layer at the bottom of the pipe.

5. CONCLUSIONS

1. Surfactant dosages of 2000 p.p.m. were required to produce emulsions of sufficient durability for recirculating flow in a 53 mm test pipeline.
2. Durability is strongly dependent on surfactant dosage, water content, sand content and pump type.
3. The effect of temperature on flow resistance is primarily the effect of changing the viscosity of the continuous (brine) phase.
4. The volume fraction of the continuous phase is a useful correlating parameter for emulsion apparent viscosities.
5. Droplet migration away from the pipe wall appears to occur in laminar flow. For this reason generalization of pipeline (or viscometer) test results should be undertaken with caution.
6. Sand in the crude oil is released to the water phase. The flow resistance of sand–oil–water mixtures is complex and depends, in part, on the water content of the oil.
7. Small amounts of sand have a strong effect upon flow resistance.
8. The deposition velocity for sand in laminar flow is strongly dependent upon emulsion effective viscosity.

SYMBOLS

C	Volume fraction dispersed phase	(–)
D	Pipe diameter	(m)
L	Pipeline Length	(m)
V	Mean or bulk velocity of flow	(m/s)
y	Distance measured upward from bottom of pipe	(m)
ΔP	Pressure drop	(Pa)
μ	Viscosity (Single Phase)	(Pa–s)
μ_m	Viscosity (Mixture)	(Pa–s)
μ_L	Continuous Phase Viscosity	(Pa–s)

ACKNOWLEDGEMENTS

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FIGURES

Figure 1: Experimental test pipeline

Figure 2: Time to inversion as a function of surfactant concentration in bench scale tests.

Figure 3: Time to inversion as a function of added water content in bench scale tests.

Figure 4: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil A with no sand added.

Figure 5: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with no sand added.

Figure 6: Correlation of effective viscosity with volume fraction and added brine.

Figure 7: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil A with 0.5% sand.

Figure 8: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil A with 3% sand.

Figure 9: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with 0.5% sand.

Figure 10: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with 1.5% sand.

Figure 11: Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with 3% sand.

Figure 12: Time to inversion for oil B emulsions as a function of sand content in bench scale tests.

Figure 13: Pipe cross section showing triangular finite element grid.

Figure 14: Viscosity variation in the vertical plane used in the computer simulation.

Figure 15: Point velocities measured and predicted by the computer simulation for oil B emulsion.

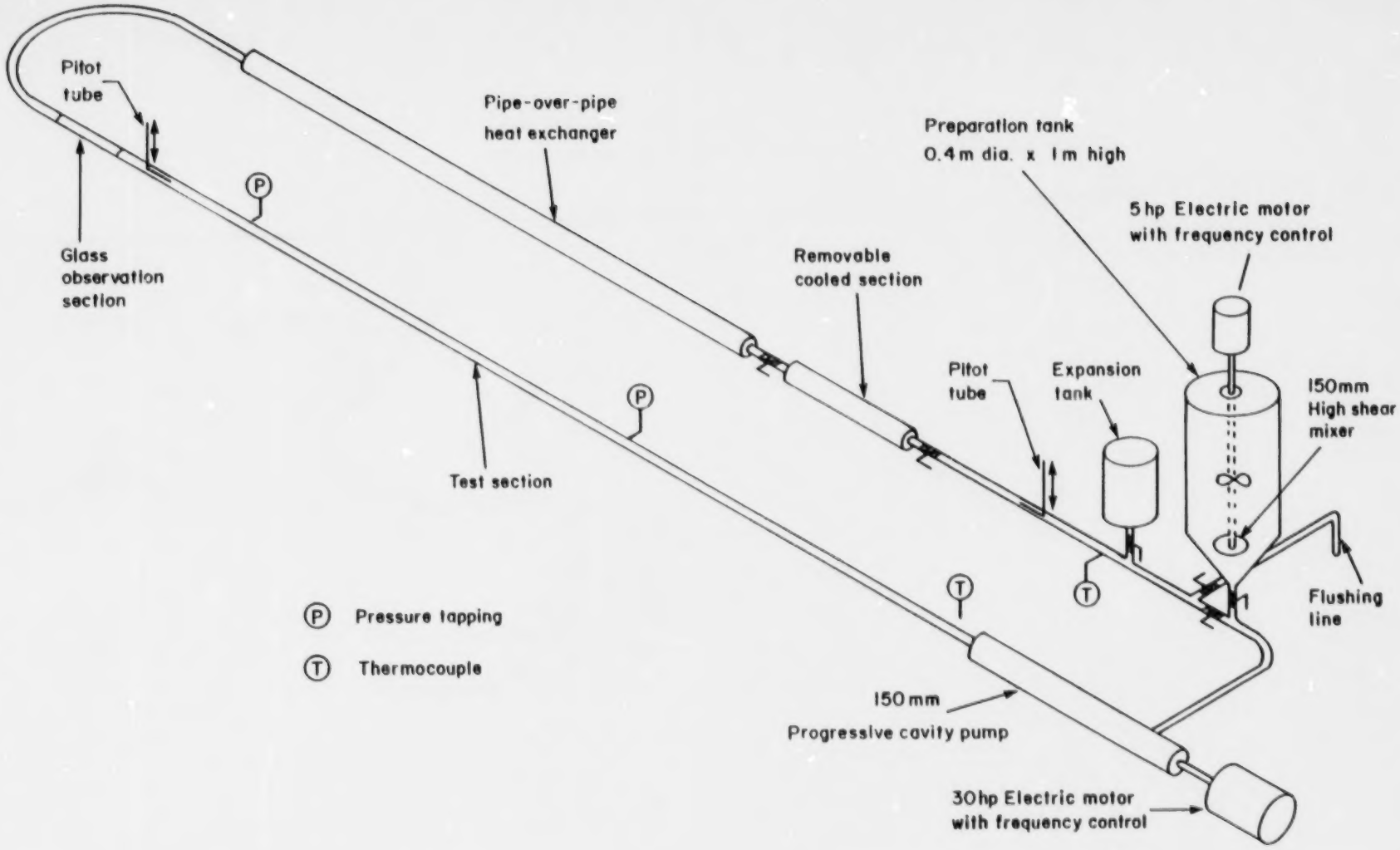

Figure 1. 50mm PIPELOOP

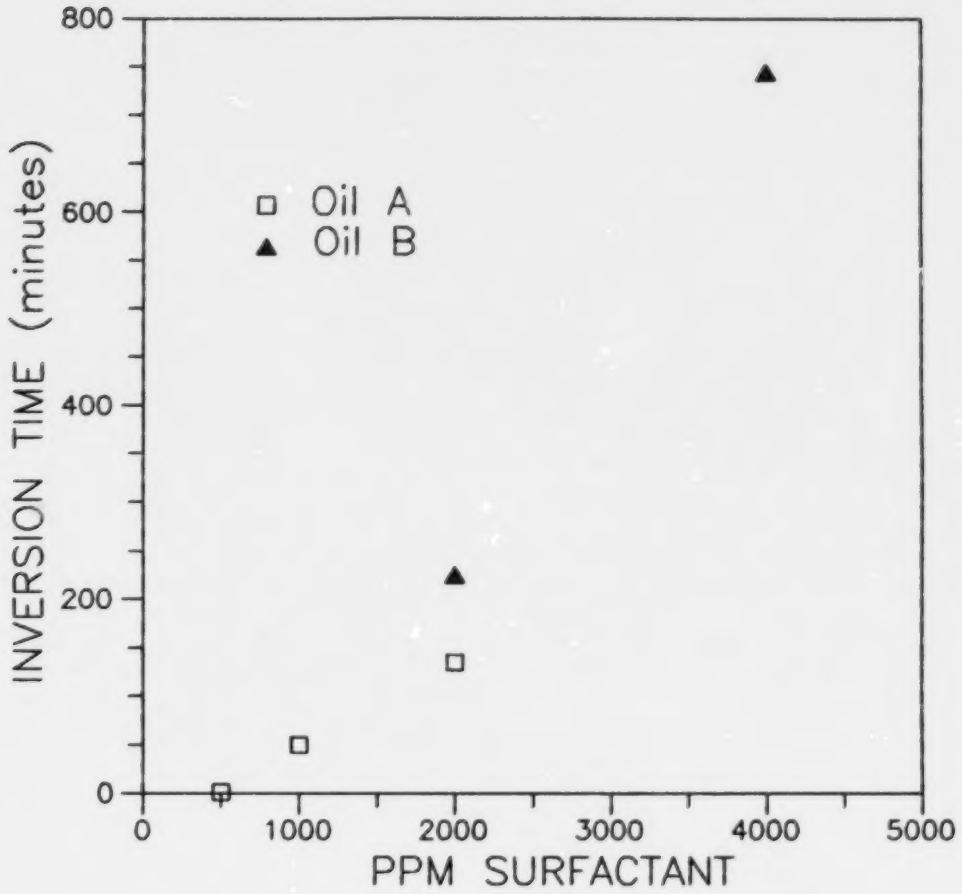

Figure 2. Time to inversion as a function of surfactant concentration in bench scale tests.

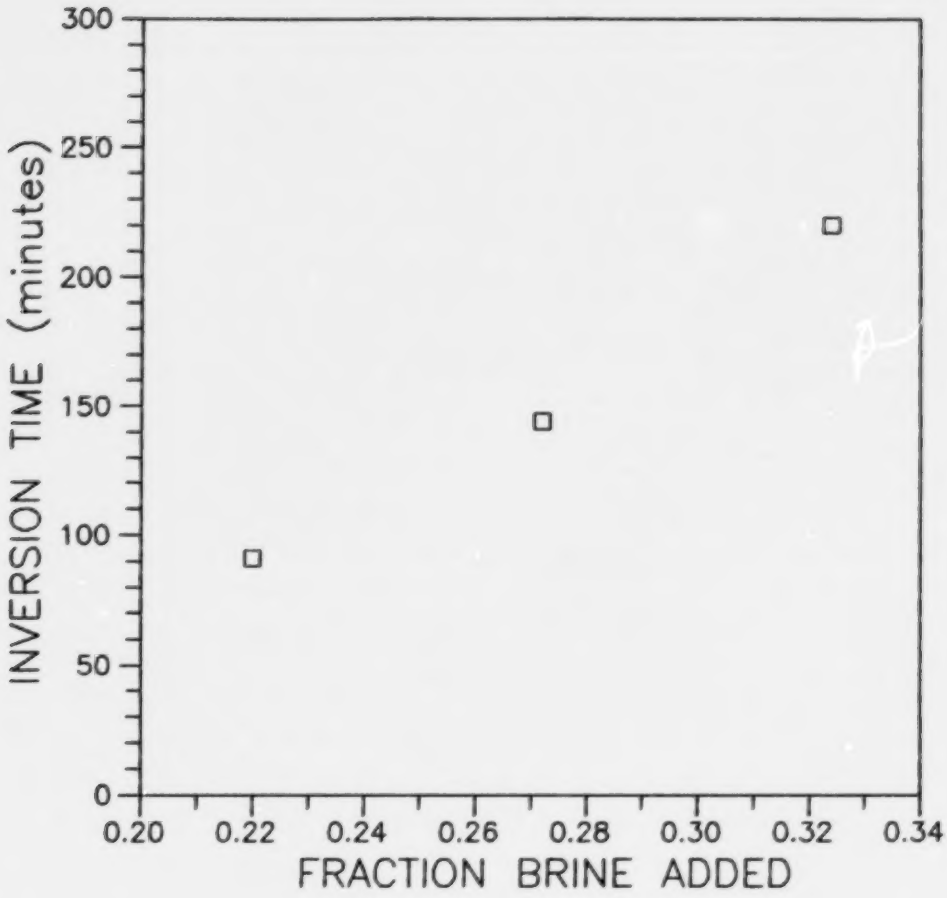

Figure 3. Time to inversion as a function of added water content in bench scale tests.

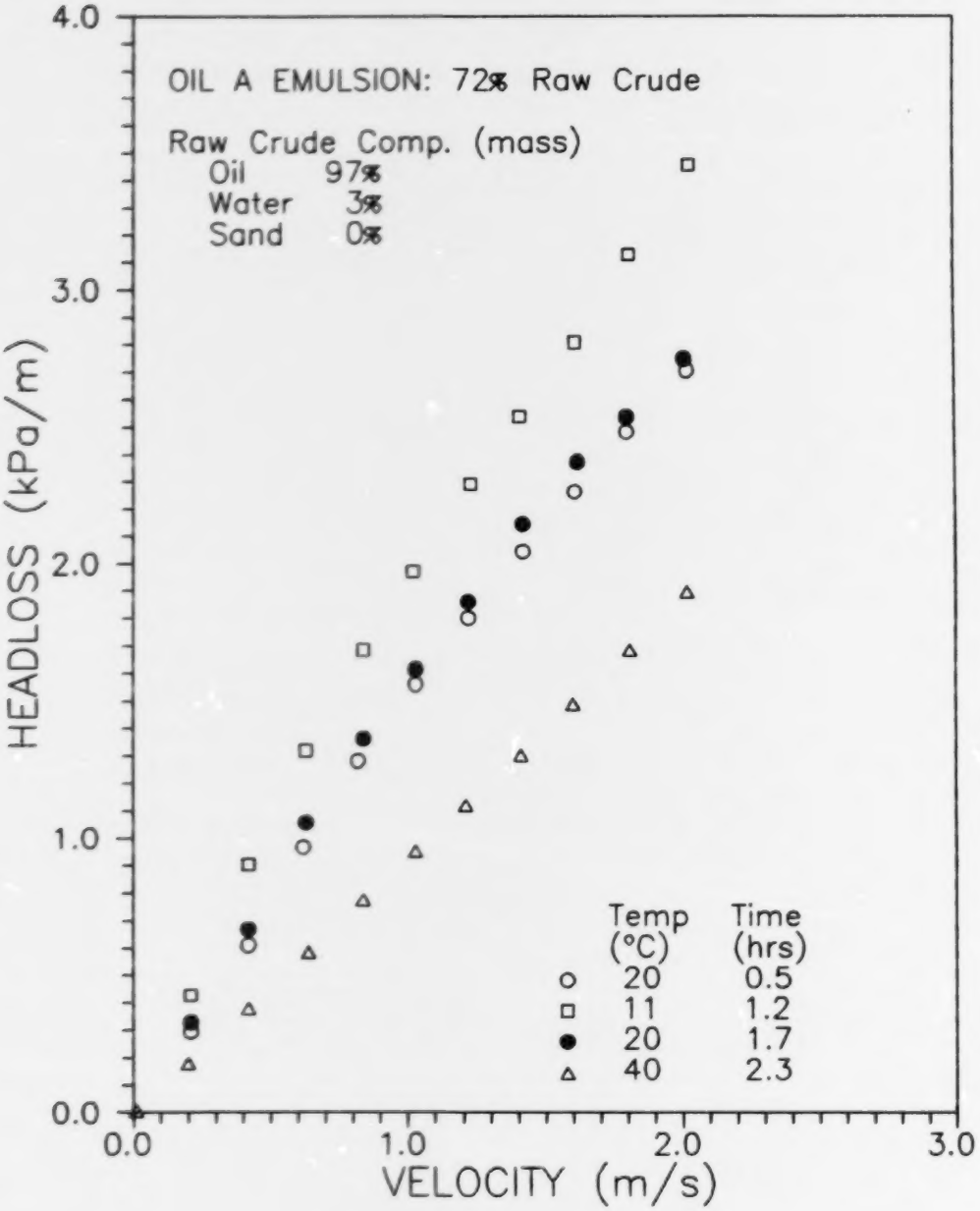

Figure 4. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil A with no sand added.

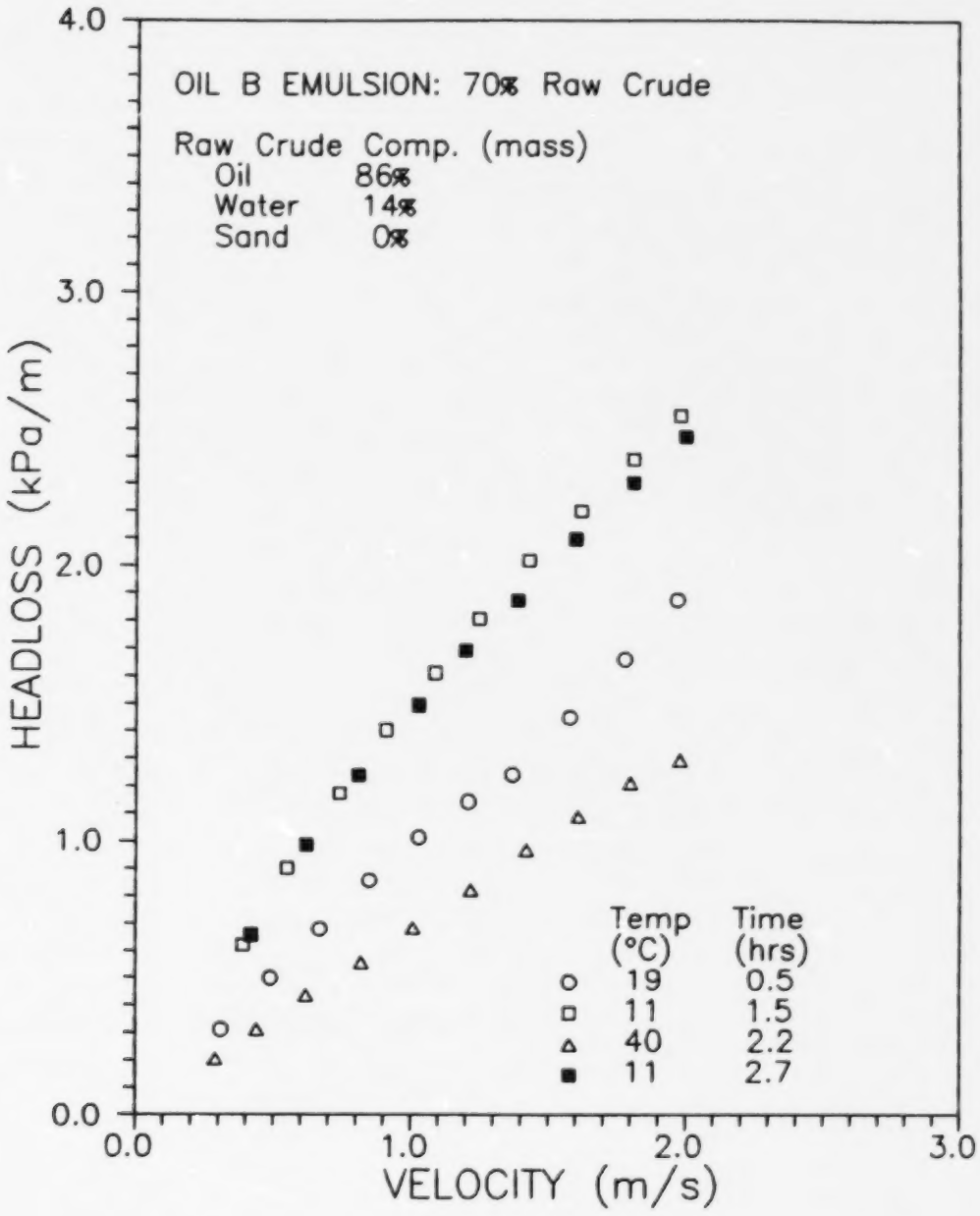

Figure 5. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with no sand added.

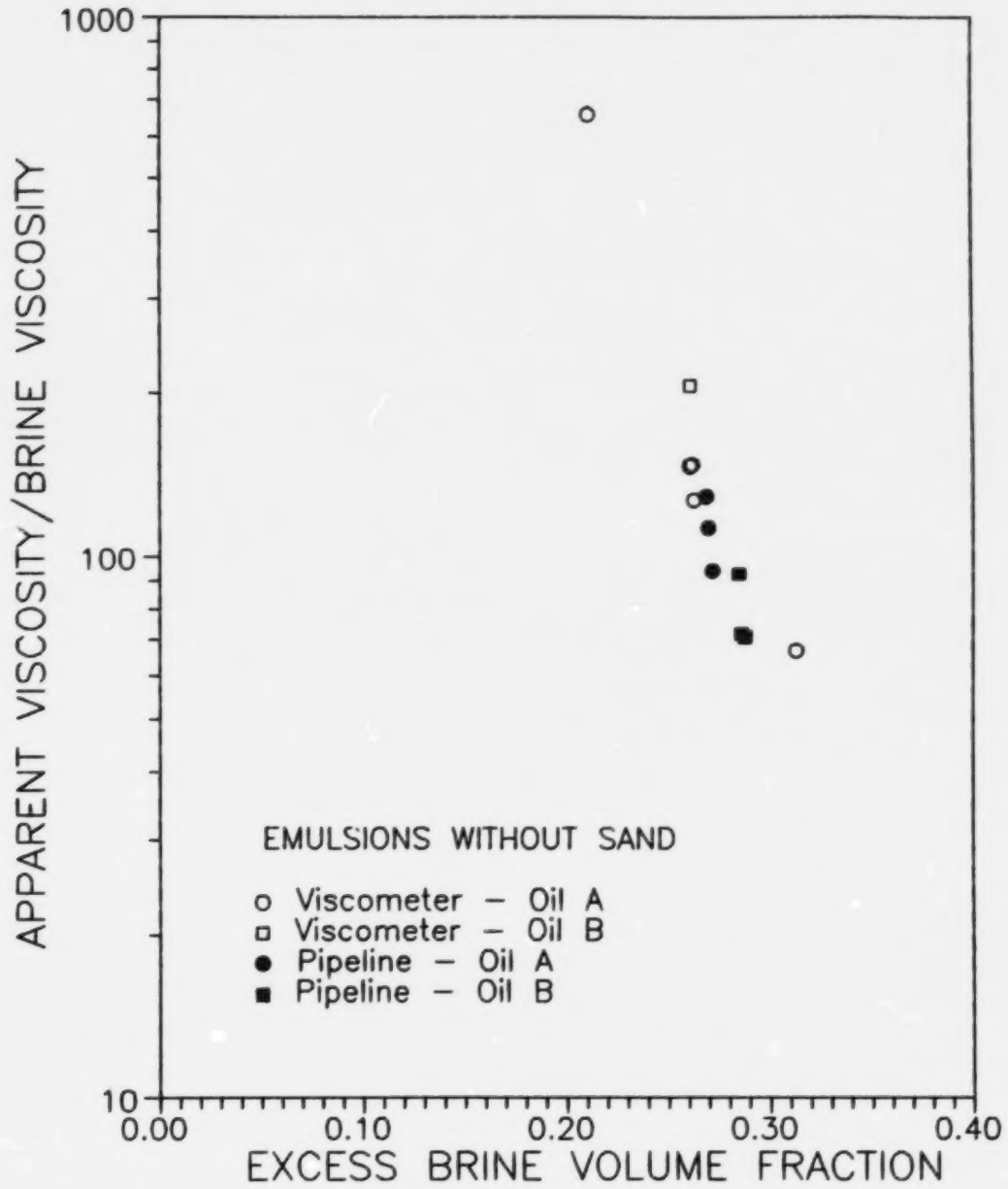

Figure 6. Correlation of effective viscocity with volume fraction and added brine.

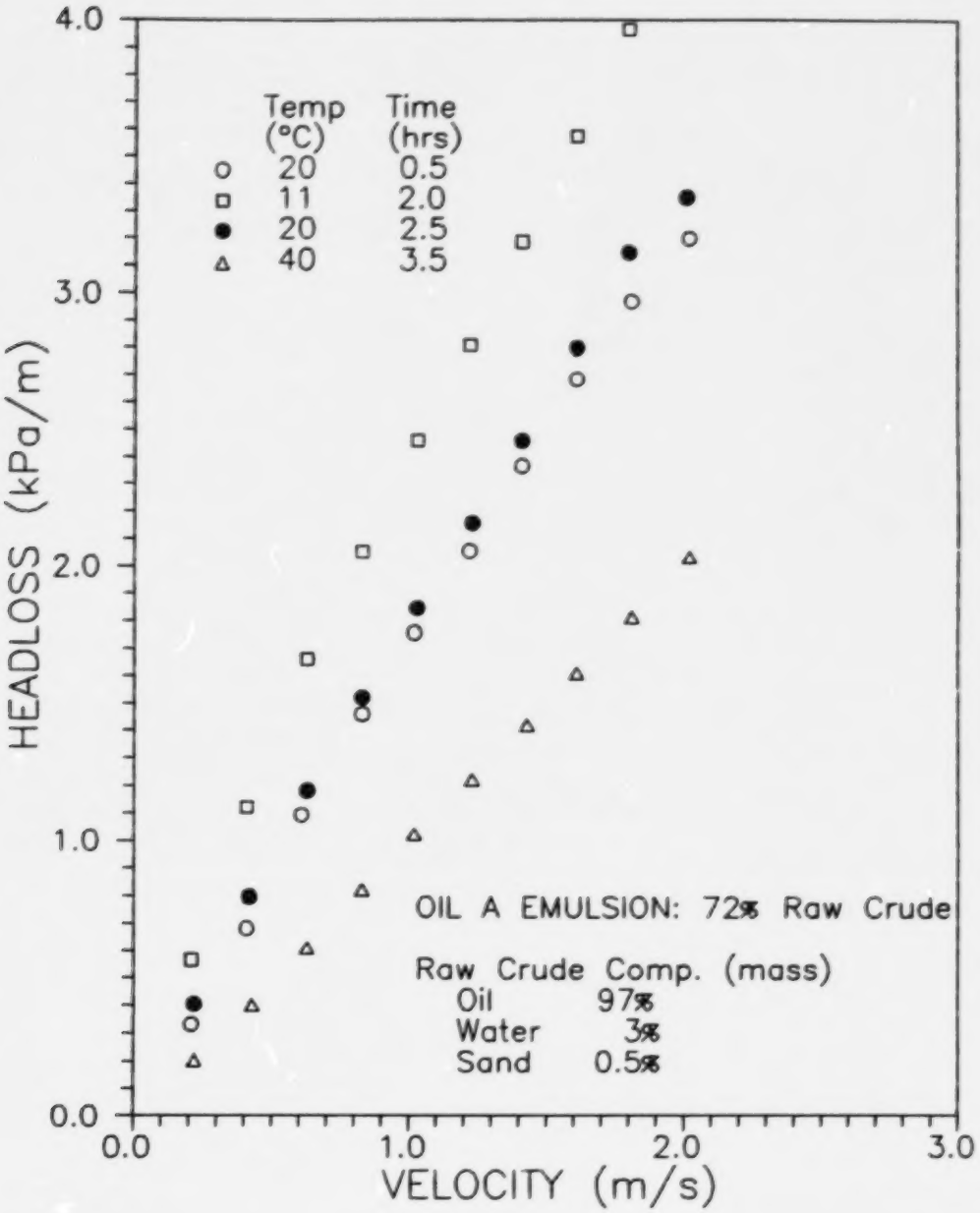

Figure 7. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil A with 0.5% sand.

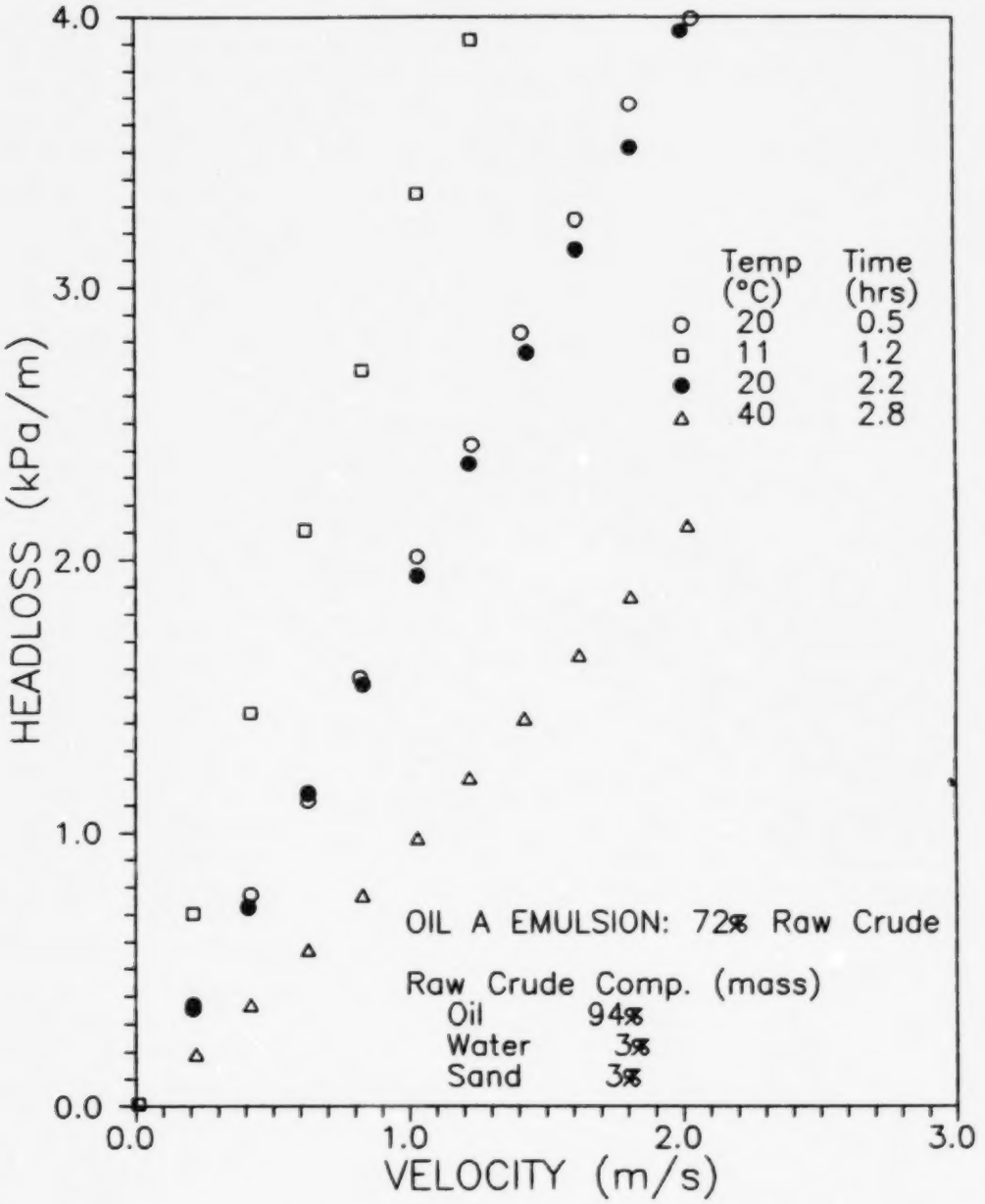

Figure 8. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil A with 3% sand.

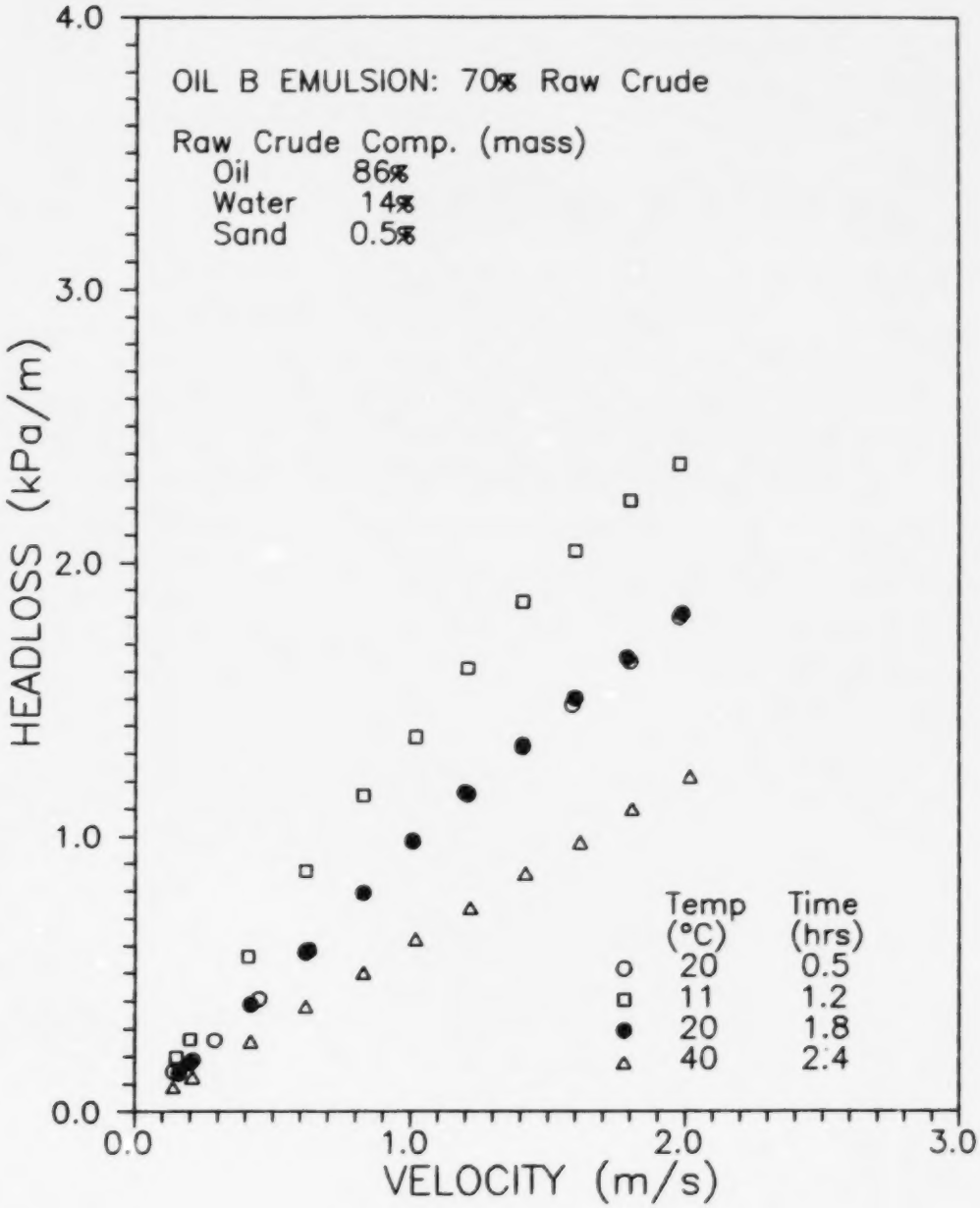

Figure 9. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with 0.5% sand.

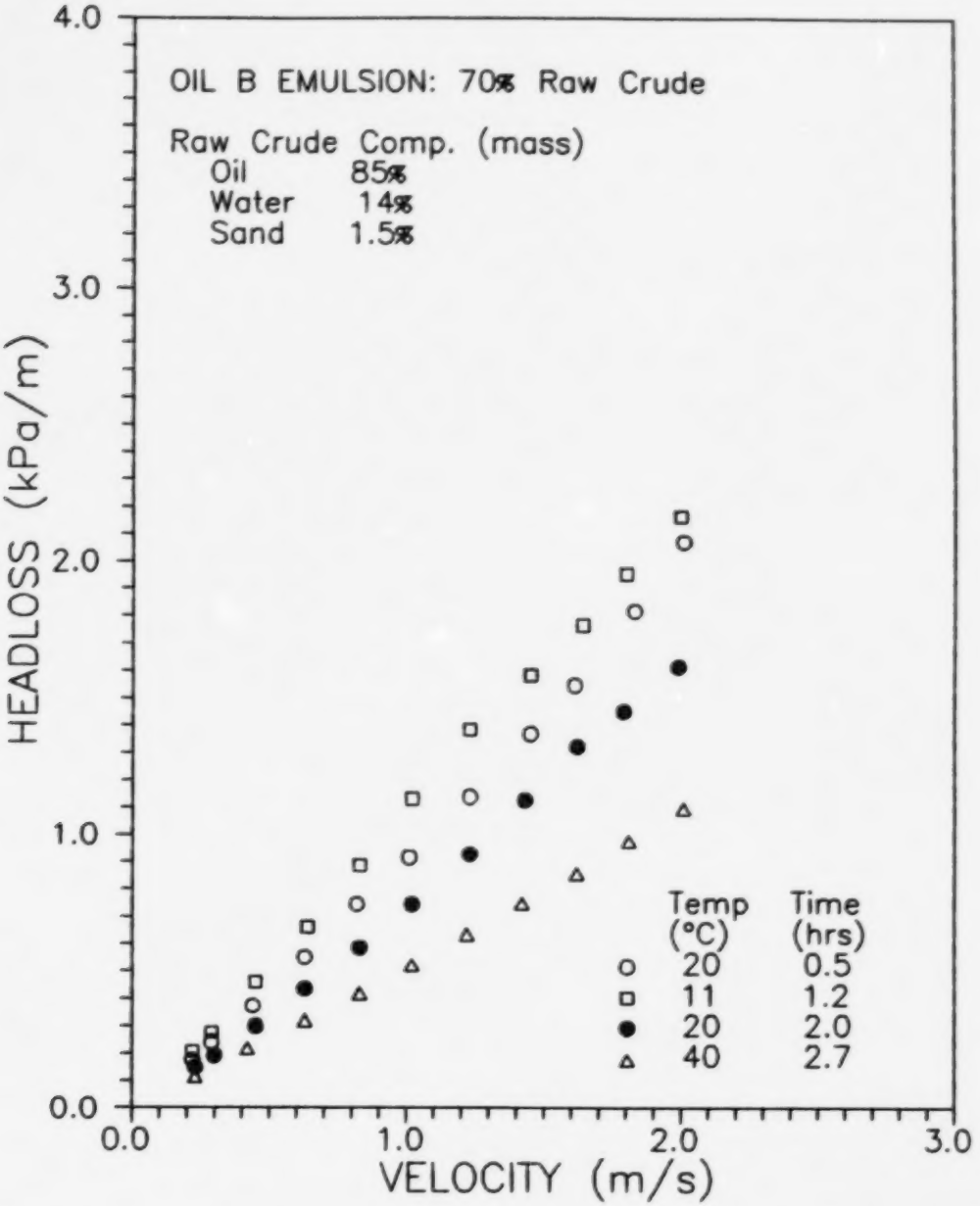

Figure 10. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with 1.5% sand.

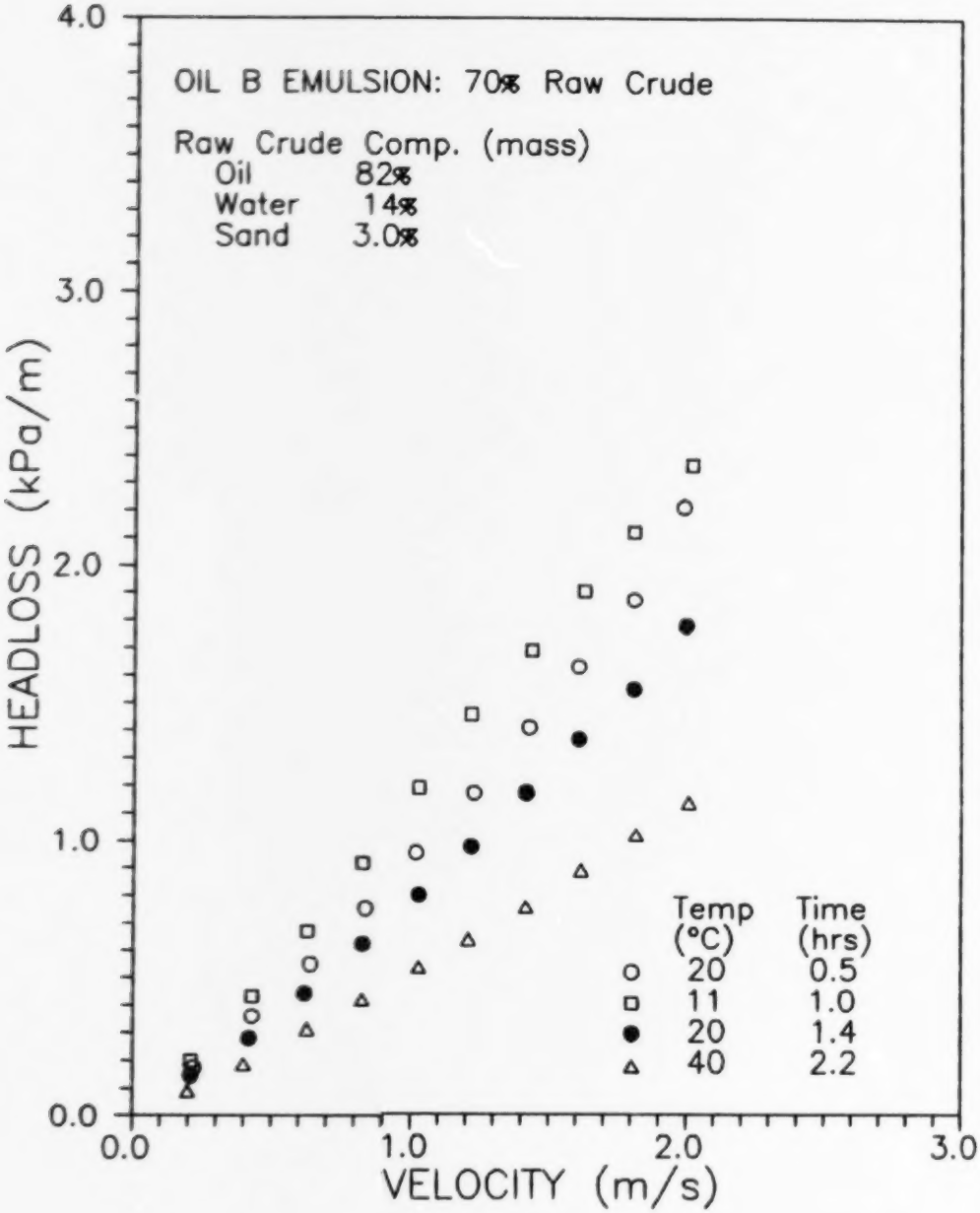

Figure 11. Effects of velocity, temperature and pumping time on headloss for emulsion prepared using Oil B with 3% sand.

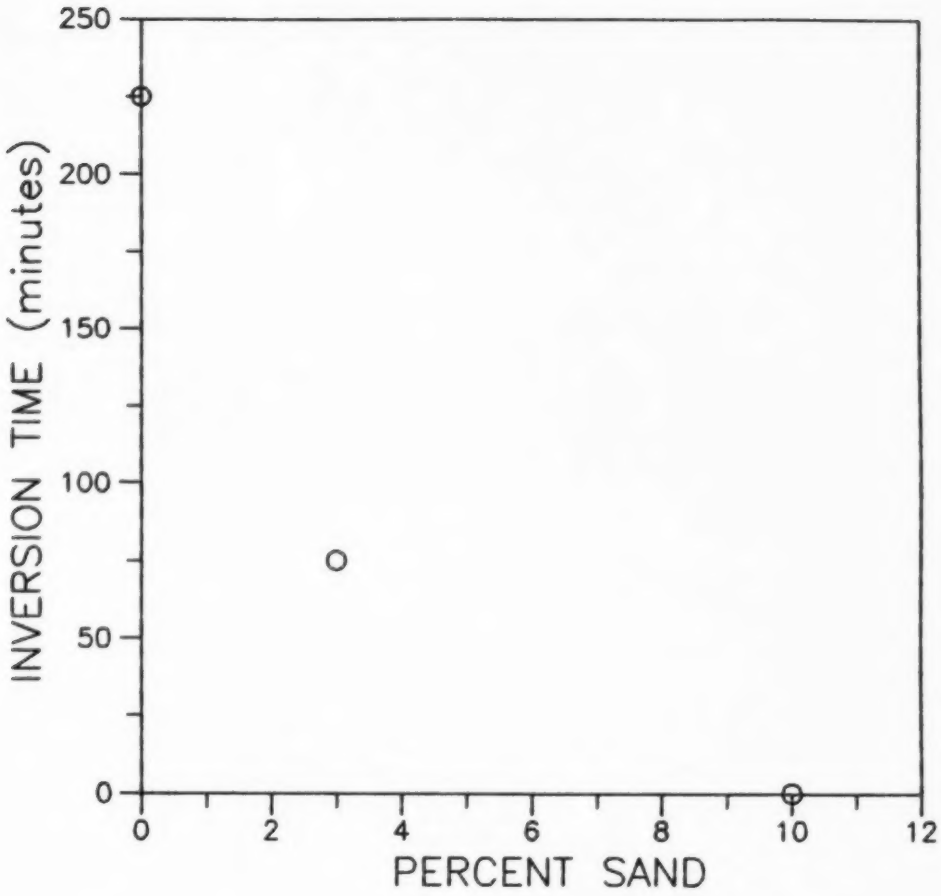

Figure 12. Time to inversion for oil B emulsions as a function of sand content in bench scale tests.

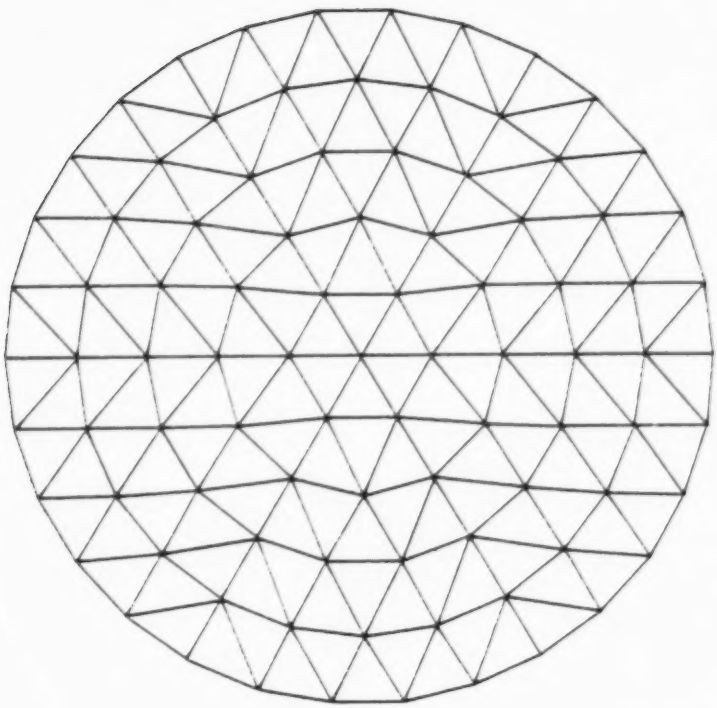

Figure 13. Pipe cross section showing triangular finite element grid.

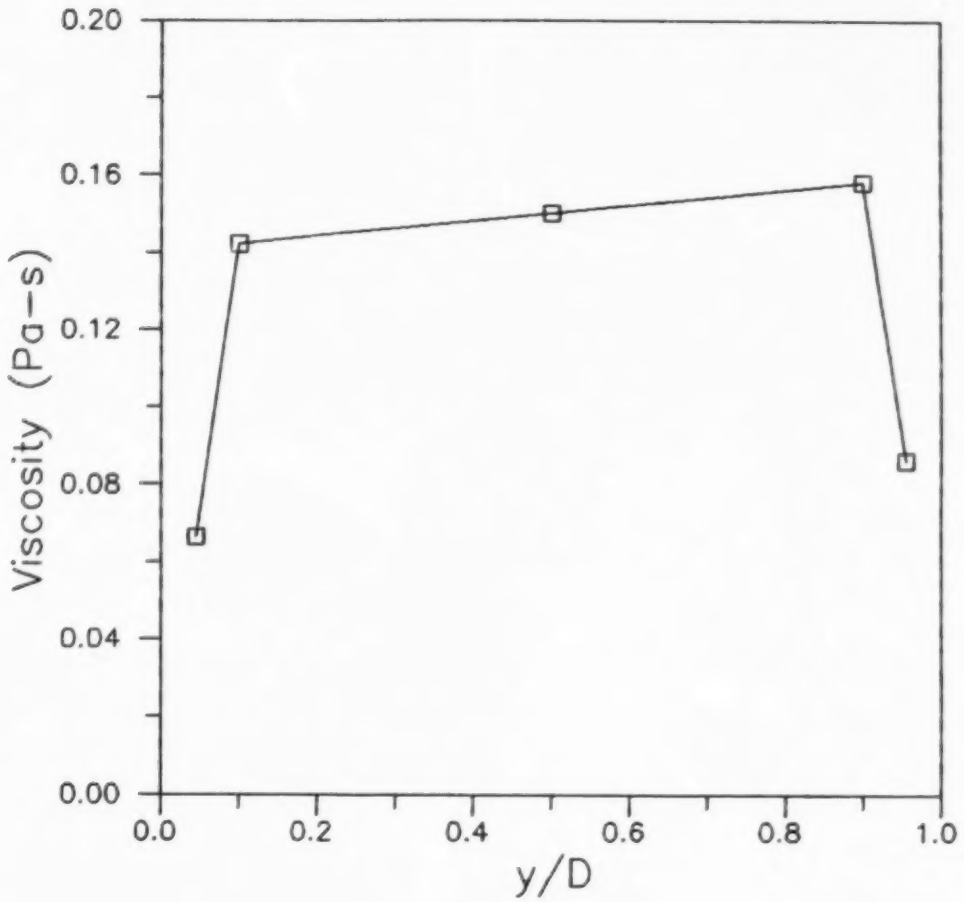

Figure 14. Viscosity variation in the vertical plane used in the computer simulation.

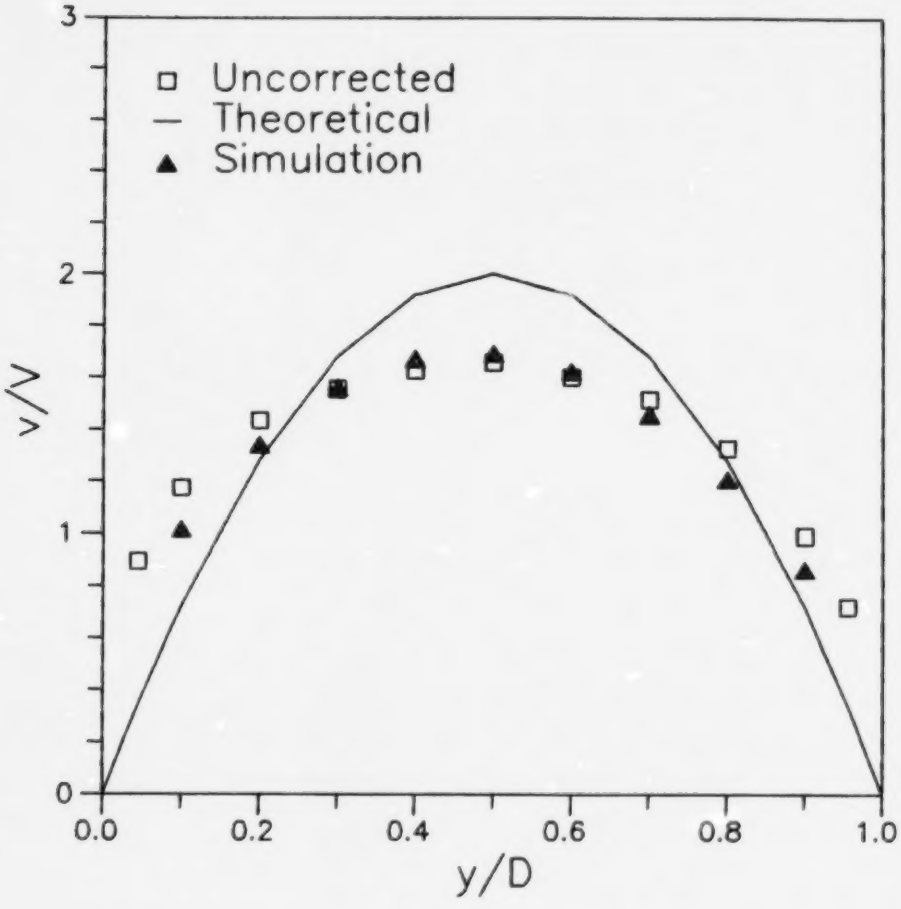

Figure 15. Point velocities measured and predicted by the computer simulation for oil B emulsion.

APPENDIX A

SRC 53 mm DIAMETER PIPELOOP FLOW DATA

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890503

OIL B EMULSION: 70% Raw Crude

Raw Crude Composition (mass)

Oil %	86
Water %	14
Sand %	0

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.21	1142	20.1
1.03	1013	19.7
0.85	856	19.3
0.67	679	19.2
0.49	499	19.0
0.31	310	19.0
1.58	1449	19.1
1.78	1662	19.2
1.97	1878	19.4

Circ. Time (hr): 1.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.97	2490	10.6
1.98	2551	10.7
1.81	2391	10.9
1.62	2200	10.9
1.43	2021	10.5
1.25	1809	10.6
1.09	1612	10.6
0.91	1403	10.8
0.74	1173	10.8
0.55	901	11.0
0.39	619	11.0

Circ. Time (hr): 2.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.98	1296	40.1
1.80	1212	40.0
1.61	1088	40.0
1.42	966	39.7
1.22	821	40.0
1.01	682	40.0
0.82	558	40.0
0.62	435	39.8
0.44	310	40.0
0.29	203	40.1

Circ. Time (hr): 2.7

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.00	2475	10.7
1.81	2304	10.8
1.60	2098	11.0
1.39	1874	11.0
1.20	1693	10.4
1.03	1494	10.3
0.81	1237	10.3
0.62	985	10.3
0.42	656	10.4

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890504

OIL B EMULSION: 70% Raw Crude

Raw Crude Composition (mass)

Oil %	86
Water %	14
Sand %	0.5

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.98	1775	20.2
1.98	1801	20.4
1.80	1639	20.8
1.59	1479	20.0
1.41	1327	19.6
1.21	1153	19.4
1.01	981	19.3
0.83	794	19.3
0.62	576	19.2
0.45	408	19.2
0.29	258	19.2
0.21	185	19.2
0.14	143	19.1

Circ. Time (hr): 1.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.98	2362	11.1
1.80	2229	10.5
1.60	2044	10.3
1.41	1858	10.3
1.21	1613	10.3
1.02	1361	10.5
0.83	1148	10.4
0.62	874	10.4
0.41	561	10.4
0.20	262	10.5
0.15	196	10.4

Circ. Time (hr): 1.8

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.99	1781	20.0
1.99	1815	20.6
1.79	1651	20.7
1.60	1504	20.5
1.41	1330	20.2
1.20	1158	20.2
1.01	983	20.1
0.83	794	20.1
0.63	583	20.1
0.42	388	20.1
0.20	175	20.1
0.16	139	20.1

Circ. Time (hr): 2.4

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	1219	40.0
1.81	1100	40.1
1.62	979	40.0
1.42	865	39.8
1.22	738	39.6
1.02	625	39.4
0.83	501	39.2
0.62	379	39.7
0.42	253	39.7
0.21	124	39.5
0.14	88	39.4

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890505

OIL B EMULSION: 70% Raw Crude

Raw Crude Composition (mass)

Oil %	85
Water %	14
Sand %	1.5

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.01	2136	19.8
2.01	2072	20.0
1.83	1819	20.5
1.61	1549	20.7
1.45	1372	20.3
1.23	1139	20.1
1.01	917	20.0
0.82	744	19.9
0.63	550	19.9
0.44	373	19.9
0.29	239	19.9
0.22	174	19.9

Circ. Time (hr): 1.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.00	2166	10.4
1.80	1955	10.6
1.64	1768	10.7
1.45	1585	10.5
1.23	1387	10.6
1.02	1132	10.7
0.83	888	10.9
0.64	661	10.5
0.45	461	10.4
0.29	275	10.6
0.22	206	10.6

Circ. Time (hr): 2.0

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.99	1616	20.3
1.79	1453	20.0
1.62	1324	19.2
1.43	1127	19.9
1.23	929	20.6
1.02	744	20.7
0.83	586	20.9
0.63	436	20.9
0.45	298	20.9
0.30	191	20.9
0.23	147	21.0

Circ. Time (hr): 2.7

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.01	1097	40.0
1.81	978	40.2
1.62	858	40.2
1.42	748	40.0
1.22	635	39.9
1.02	523	39.9
0.83	420	39.8
0.63	319	39.6
0.42	216	39.6
0.23	113	39.4

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890506

OIL B EMULSION: 70% Raw Crude

Raw Crude Composition (mass)

Oil %	82
Water %	14
Sand %	3.0

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
1.99	2212	20.1
1.81	1874	20.5
1.61	1630	20.2
1.43	1409	20.0
1.23	1168	20.0
1.02	951	19.9
0.84	754	19.9
0.64	549	19.9
0.43	360	19.9
0.22	173	19.8

Circ. Time (hr): 1.0

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	2366	10.4
1.81	2121	10.6
1.63	1906	10.4
1.44	1690	10.3
1.22	1455	10.4
1.03	1188	10.4
0.83	918	10.6
0.63	668	10.8
0.43	433	10.8
0.21	197	11.0

Circ. Time (hr): 1.4

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.00	1740	20.7
2.00	1779	20.0
1.81	1548	20.8
1.61	1366	19.9
1.42	1170	19.6
1.22	974	19.4
1.03	796	19.5
0.83	623	19.5
0.62	442	19.4
0.42	280	19.5
0.21	146	19.5

Circ. Time (hr): 2.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.00	1103	40.4
2.01	1136	40.5
1.82	1019	40.5
1.62	889	40.5
1.42	755	40.4
1.21	635	40.3
1.03	532	40.2
0.83	422	40.1
0.63	312	40.4
0.40	186	40.7
0.20	90	40.3

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890507

OIL A EMULSION: 72% Raw Crude

Raw Crude Composition (mass)

Oil %	97
Water %	3
Sand %	0.0

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	2646	19.7
2.02	2706	19.5
1.80	2481	19.4
1.61	2264	19.4
1.42	2044	19.6
1.22	1800	19.6
1.03	1560	19.6
0.82	1282	19.6
0.62	968	19.7
0.42	611	19.7
0.21	293	19.7

Circ. Time (hr): 1.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	3381	11.0
2.03	3455	10.6
1.81	3129	10.5
1.61	2807	10.7
1.41	2538	10.8
1.23	2292	10.9
1.02	1971	10.9
0.84	1685	10.9
0.63	1320	10.8
0.42	904	10.9
0.21	428	10.9

Circ. Time (hr): 1.7

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.01	2748	20.4
1.80	2536	20.3
1.62	2372	19.7
1.42	2144	19.6
1.22	1860	19.8
1.03	1615	19.9
0.84	1363	19.9
0.63	1058	20.1
0.42	669	20.1
0.21	327	20.1

Circ. Time (hr): 2.3

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	1898	39.9
1.81	1686	40.2
1.60	1488	40.1
1.41	1305	40.0
1.21	1121	39.8
1.03	954	39.6
0.84	776	39.5
0.64	584	39.6
0.42	379	39.6
0.20	179	39.5

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890508

OIL A EMULSION: 72% Raw Crude

Raw Crude Composition (mass)

Oil %	97
Water %	3
Sand %	0.5

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	3198	19.8
1.81	2969	20.0
1.61	2684	20.1
1.41	2365	20.1
1.22	2055	20.3
1.02	1757	20.3
0.83	1459	20.3
0.61	1092	20.4
0.41	680	20.4
0.21	331	20.4

Circ. Time (hr): 2.0

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.01	4107	11.2
2.01	4322	10.8
1.80	3966	10.5
1.61	3573	10.7
1.41	3185	10.7
1.22	2808	10.7
1.03	2457	10.8
0.83	2052	10.6
0.63	1658	10.6
0.41	1119	10.6
0.21	566	10.7

Circ. Time (hr): 2.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.01	3349	19.7
1.80	3145	19.7
1.61	2797	20.1
1.41	2458	20.5
1.23	2156	20.7
1.03	1847	20.8
0.83	1519	20.5
0.63	1181	19.8
0.42	795	19.7
0.22	405	19.6

Circ. Time (hr): 3.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	2033	39.8
1.81	1816	40.0
1.61	1610	40.0
1.43	1421	39.9
1.23	1221	39.6
1.02	1022	39.4
0.83	821	39.5
0.63	610	39.9
0.43	400	40.0
0.22	201	39.9

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890509

OIL A EMULSION: 72% Raw Crude

Raw Crude Composition (mass)

Oil %	94
Water %	3
Sand %	3.0

Circ. Time (hr): 0.5

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.04	3994	20.5
1.81	3677	20.4
1.61	3252	20.1
1.41	2832	20.0
1.23	2422	20.0
1.03	2012	20.0
0.82	1567	20.0
0.63	1180	20.0
0.42	773	20.0
0.21	370	19.9

Circ. Time (hr): 1.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	6921	10.7
1.81	6172	10.7
1.62	5322	10.6
1.41	4472	10.7
1.23	3913	10.5
1.03	3347	10.5
0.83	2695	10.6
0.62	2108	10.5
0.42	1439	10.5
0.21	704	10.6

Circ. Time (hr): 2.2

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.00	3948	20.2
1.81	3518	19.7
1.61	3141	19.3
1.43	2761	19.2
1.22	2354	19.3
1.03	1944	19.2
0.83	1543	19.3
0.63	1146	19.4
0.41	726	19.4
0.21	357	19.4

Circ. Time (hr): 2.8

Velocity (m/s)	Headloss (Pa/m)	Temp. (C)
2.02	2128	39.9
1.81	1868	40.1
1.62	1652	40.0
1.42	1421	39.7
1.22	1204	39.4
1.03	981	39.8
0.83	771	39.9
0.63	571	39.9
0.42	369	39.6
0.22	191	39.5

SASKATCHEWAN RESEARCH COUNCIL PIPELINE TECHNOLOGY DATA

RUN NUMBER: S890511

OIL B EMULSION: 70% Raw Crude

Raw Crude Composition (mass)

Oil%	86
Water	14
Sand	0

Local Velocity (m/s): Uncorrected Pitot Tube Data

y/D	Bulk Velocity (m/s) 0.91	1.81	1.88
0.955	0.67	1.31	1.41
0.900	0.93	1.78	1.91
0.800	1.24	2.40	2.53
0.700			2.89
0.600			3.04
0.500	1.65	3.03	3.11
0.400			3.09
0.300			2.95
0.200	1.40	2.62	2.70
0.100	1.21	2.12	2.24
0.045	0.95	1.61	1.71